BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the Matters of	Docket No. 14-RPS-01
Amendments to Regulations Specifying Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities	
California Air Resources Board Pre-Rulemaking to Consider Potential Regulations on Renewables Portfolio Standard Penalties for Local Publicly Owned Electric Utilities	

JOINT STAFF WORKSHOP

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
First Floor, Art Rosenfeld Hearing Room
(Hearing Room A)
SACRAMENTO, CALIFORNIA

THURSDAY, April 9, 2015
9:00 A.M.

Reported by:
Kent Odell

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(* Via WebEx)

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P R O C E E D I N G S

APRIL 9, 2015 9:32 a.m.

MS. GOULD: Okay, good morning everyone and welcome to our workshop. I'm Angie Gould. I am in the Renewable Energy Division here at the California Energy Commission, and I'm the Technical Lead for the RPS Verification and Compliance.

I'm joined by, from the ARB, Dave Mehl and Craig Segall, and also Gabe Herrera is to the left from our Legal Office, and Emily Chisolm for POU Compliance for the RPS.

We also have Kevin Chou running our WebEx and Adam Van Winkle who will be collecting blue cards for your comments. So if you have one, make sure you raise your hand and we'll come get that for you.

So today I'll be going over a few background items, just housekeeping, purpose of the workshop, the background for the RPS Regulations, then I'll get into the Proposed Modifications for the Regulations section by section, followed by a brief presentation from the ARB, just an oral presentation, and then next steps.

So handouts were on the desk at the room entrance next to the sign-in sheet and I hope everyone in the room did sign in. We use that for our rulemaking file.

The restrooms are located here on the first floor, just that way. We have a snack bar on the second floor across from the top of the stairs. And there are several restaurants within walking distance for lunch.

Emergency evacuation procedures, if there is an alarm that goes off, anything like that, just follow the Energy Commission staff out the front doors and across to Roosevelt Park.

We are running this meeting through WebEx and this meeting is being recorded via WebEx, as well, and it will be available on the Energy Commission’s website afterward, and we’re also being transcribed by a Court Reporter. And this presentation will also be available on the Energy Commission’s website.

For those of you in the room, fill out your blue cards and hand it in to Adam and you’ll be called up to the podium. Those of you who are commenting via WebEx, just use the raised hand feature and we’ll unmute you when it’s your turn.

And when we get to the end of the WebEx comment portion, we'll be opening up all of the phone lines, and please only unmute your phone to ask a question, so I would ask that all of you on the phone, to keep things somewhat sane when we get to that point, make sure you mute yourselves.

Written comments, please submit these according to the directions in the NOPA that is available on the Energy Commission's website.

The purpose of this workshop is to discuss the rulemaking process and the proposed modifications to the RPS Regulations for POUs, as well as ARB's potential development of an RPS Penalty Regulation.

We'd also like to encourage and facilitate all public participation, again, thank you for joining, and we're here to receive your oral and written comments on the proposed modifications, as well as the potential RPS Penalty Regs.

So Senate Bill 591 became effective January 2014 and SB 591 establishes a limited procurement exemption for a POU that gets more than 50 percent of its annual retail sales from its own qualifying hydro generation.

If a POU meets those criteria, then it may limit its RPS Procurement for a given compliance period to the lessor of the retail sales not met by its own hydro, the RPS Procurement target that is applicable to all POUs, or the amount of procurement that's capped by the cost limitation.

The pre-rulemaking phase began with the Order Instituting Rulemaking that was adopted in March 2014, and then we held a Scoping Workshop July 11th of 2014, and we received 15 sets of written comments. And then much background work after that.

We started the formal APA Rulemaking phase March 27th with the publishing of the NOPA, and OAL's Notice Register. We also posted Rulemaking documents on the Energy Commission's website, those were made available to the public on that same date. That includes the Notice of Proposed Action, or NOPA, the Proposed Modifications that are also called "Express Terms," the Initial Statement of Reasons, or ISOR, and supporting materials for the economic and fiscal impact statements.

The NOPA included a Notice of this Staff

Workshop, as well as the Adoption Hearing, it included Public Comment Instructions, and gave the availability of documents. And the ISOR includes the rationale for all of the proposed changes that we're making to the Regulations.

The supporting materials for the Economic and Fiscal Impact Statement estimated a total annual fiscal impact to the POUs of $7,154.00.

So during this formal APA Rulemaking Phase, all oral and written comments are recorded and included in our rulemaking file. The Energy Commission adoption hearing for the proposed regulations is scheduled for June 10th at our Regular Business Meeting, and once the rulemaking is completed, the final rulemaking package will be submitted to OAL for approval.

Copies of all the documents are available on our website that you can see here, it's also listed in the NOPA, and if you are having difficulty accessing them through our website, you can also contact CEC staff.

Okay, so we start with Section 3201, which gives the Definitions. We've revised the definition of "bundled" so that REC associated with the onsite use of electricity could be considered bundled only if the eligible resources owned by the POU retiring the REC. If the resource is owned by a third party, or by the customer where the resource is located, that would not be considered bundled.

We add a definition of resale, or resold, so in this case it may be from any entity, not just from another RPS obligated entity, and it's the resale of contracts only, rather than ownership agreements, as that would just be a sale.

We've revised the definition of Western Electricity Coordinating Council, or WECC, to clarify the relationship to NERC, just for accuracy. And we also renumbered various subdivisions to accommodate the addition of resale.

In Section 3202, we added subsection A(3)(c), so this clarifies how electricity products under a contract met the criteria of Section 3202(A)(3), so that's the contract executed before June 1st, 2010 that did not meet the RPS rules that were in place at the time. It clarifies how those electricity products will be considered if that contract is subsequently amended. And this is consistent with the contract amendment rules outlined in Section 3202(A)(2)(b) for those count in full resources.

In Section 3203, we've revised Subsection (A)(1)(d), so for RECs from a resource with a data electronic transfer agreement that are to be classified as PCC1, the associated electricity must be scheduled into a California Balancing Authority on an hourly or sub-hourly basis, it's no longer enough to simply have a dynamic transfer agreement in place. So this aligns the electricity products procured under dynamic transfer agreements with the other PCC1 electricity products.

In Section 3204, we've revised Subsection (A)(7)(c), so this extended the averaging period to qualify for the exemption under PUC Section 399.30J from seven to 20 years. So this is consistent with the requirements for the incremental hydro baseline and the RPS Eligibility Guidebook, we felt that that was a more appropriate comparison than to the seven-year averaging period that was included for PURPA in the statute.

We've also added Subsection (A)(10) to

Section 3204 to implement the requirements of SB 591, so this also includes a 20-year averaging period to qualify for the exemption, and the qualifying for and calculating the exemption is based on the qualifying hydro production and not what the POU procures.

The eligibility for the exemption is determined on a compliance period basis and the POU must comply on a compliance period basis rather than annually. And the exemption does not excuse the POU from the Portfolio Balance requirements.

Section 3206, we've revised the Subsection (A)(1)(a)(iii), so this is to clarify the excess procurement calculation if contracts are amended to add time.

We've also added Subsections (E) and (F) to allow for partial waivers in addition to full waivers of compliance related to the delay of timely compliance, cost limitation, or portfolio balance requirement reduction.

In Section 3207, we revised Subsection (C), we moved the Attestation requirement for accuracy so that it was reflecting the correct items that were being attested to. And we also added a requirement for POUs to report energy consumption to support the retail sales verification.

Additionally, we fixed a minor grammar error in Subsection (F) and we also added Subsections (G) and (H). Subsection (G) provides a deadline for a POU to demonstrate that it meets the criteria of PUC Section 399.3(O)(H), previously there was no deadline included.

And Subsection (H) includes the reporting requirements for a POU that meets the criteria of SB 591 or PUC Section 399.3(O)(K).

In Section 1240, we've revised Section (D) and this lists potential mitigating factors that a POU may include in its Answer to a formal complaint, and this list of mitigating factors is not exhaustive, and it's based on the factors in the Health and Safety Code Section 42403(B).

We've also revised Subsection (G) and this states that any Notices of Violation that are forwarded to the ARB may include suggested RPS penalties comparable to those adopted by the CPUC for retail sellers.

Okay, now I will hand over the mic to Dave Mehl who will give you a brief presentation from ARB.

MR. MEHL: Well, actually Craig is going to help me out on this, we're going to tag team a bit.

So SB 2, the enabling legislation of many changes for the RPS of putting it up to 33 percent, provide one aspect that ARB is to do, and that is that if the CEC has determined that there is a violation after they have concluded that action, they will forward that information to the Air Resources Board who, using our existing statutory authority, may impose penalties comparable to those imposed by the CPUC for noncompliance by retail sellers.

So we've given it a fair amount of thought on what would be the best way to implement that and we've decided that a regulation would clarify the process of how we would proceed on this. And we are at the early phases of that, so we are very pleased that the CEC asked us to participate in this, so we can interact with regulated parties and other stakeholders at an early phase of the process. So since that's happened, some changes have been introduced in the legislation that may remove us from this role. So at this point, we wanted to allow that process to move forward without us interfering.

Our timeline is we're looking to go to our Board if it's needed in the late fall. So that way, whether or not the legislation passes and we are removed, we'll see how that proceeds through the Legislation. But we're still developing a regulation, we want to talk to people regarding what our thoughts are on if we are to implement a regulation to enact this provision, what would be the best way to do it.

So with that, Craig is going to address what our thoughts are on this.

MR. SEGALL: Thanks, Dave, and thank you all for being here.

So we are in a somewhat unusual situation with the current statutory mandate, as you all know, because we are not the agency administering the regulation, nor are we in the position of determining violation, our task is a more administrative one, which is imposing this penalty consistent with our ordinary enforcement authorities and comparable to the PUC's penalty structure.

So we have in some ways a departure from our usual penalty process in which we would be in the driver’s seat gathering facts and information and imposing a penalty based solely upon our usual statutory structure. This suggests to us, both based on the test of the statute, and on the practical reality that is the CEC that will be determining the nature of the violation, whether there is a violation, and whether various waivers and exemptions apply. But our primarily role here is an administrative one.

So what we anticipate at this phase, and this is one reason why we think the CEC’s proposed amendments are so helpful, is receiving a fully developed file from the CEC identifying the nature of the violation, if there is one, any mitigating factors which we ought to consider because evidence will be developed here with expert agency that is in a position to judge the nature of the violation. And if the CEC so deems it appropriate, a recommended penalty which will of course give due regard to, as we go through our process.

We’re expecting therefore to have a fairly straightforward regulation, likely one that's quite short, that essentially explains how we will receive this fully developed file from the CEC, explain that we will work through this within our Enforcement Division, come up with a penalty, and impose it through our usual process while ensuring that that penalty is comparable, although not necessarily identical, to the penalty that would be imposed by the PUC.

So this is essentially where we are on the core approach that we're intending to take. Dave, have I omitted any points that you had raised?

MR. MEHL: I think that covers it fairly well.

MR. SEGALL: All right.

MR. MEHL: One thing I would like to say is, being at an early stage, to reiterate actually, is it gives us lots of opportunities to interact and to work with stakeholders on any of their concerns. So we're here today, we will make ourselves available if you want to either meet in person, or have a conference call to further discuss issues, if you want to go more formal feel free to send us a letter, but we are able to work at a very informal level with you.

And at a future date we will, if possible, depending on how things proceed, we will have draft regulatory language that then we will actually share and have a workshop to discuss the specific language that we have created. So there's lots of opportunities to interact with us down the road on this. Back to you.

MS. GOULD: Thank you. Okay, so the next steps, the written comments are due for the RPS Regulations on May 11th, so the instructions for written comments are in the NOPA. June 10th, again, is our proposed adoption date at an Energy Commission Business Meeting, and that would have an effective date of October 1st of this year.

And again, as Dave was saying, ARB expects to take their potential Regulations to their Board in the late fall.

The staff contacts are outlined in the Notice for this Workshop, but they're also listed here, you can contact me, and here's my number and my email address, and at the ARB you can contact Gary Collord and his number and email address are listed.

Okay, so I think I might leave those up

on the screen for a minute. But with that, we will start to take comments. So we're going to start with the people in the room, if you have blue cards, can you please raise your hand and Adam will come around and collect those from you?

Okay, we'll start with Don – I forget how to say the last name -- Ouchley, Merced Irrigation District.

MR. OUCHLEY: Don Ouchley. Can I defer to Sharon Gonsalves first?

MS. GOULD: Yes, of course.

MS. GONSALVES: Great. Thank you for having me today. My name is Sharon Gonsalves, I'm with Senator Anthony Cannella's Office, and if it's okay, I have a letter here that he wrote and I'll just read it for you guys and then we'll submit a formal copy at a later time today.

"I am proud to be the author of Senate Bill 591 that is being discussed today. This law passed out of both houses of the State Legislature without a single vote in opposition before being signed by the Governor. I appreciate the opportunity to provide input on the implementation of this law.

The community of Merced and it's local

public utility, the Merced Irrigation District, faces unique and special circumstances. This public utility serves one of the most impoverished communities not only in the state, but in the entire country. MID has a combination of physical and operational constraints on its system that affect its ability to comply with RPS.

The communities of Needles, San Francisco and Donner all received recognition of their unique and special circumstances at the time the State developed its most current Code sections pertaining to the RPS Program. Merced was seeking the same considerations.

The interpretation being proposed today does not meet the stated provisions contained in Section 399.30, Section K. The Legislature intended that this publicly-owned electric utility that receives greater than 50 percent of its annual retail sales from its own hydro-electric generation shall not be required to process excess additional renewable energy resources. Senate Bill 591 was intended to assist a single public utility in a small town, not a large investor-owned utility seeking to increase its profits.

These issues were vetted through both the Assembly and the Senate in hearing after hearing. The legislative intent was to help this community.

I strongly request you consider the intent of the Legislature as you work to implement SB 591. This bill was intended to provide real and consistent relief on an annual basis when Merced Irrigation District meets the required threshold. The Energy Commission should follow through with this intent and I look forward to continuing this dialogue as the process progresses."

Thank you.

MS. GOULD: Thank you.

MR. OUCHLEY: Good morning. Thank you very much for allowing us to speak this morning. My name is Don Ouchley, I'm the Deputy General Manager for Energy Resources at Merced Irrigation District.

For those that don't know MID, it's located in Eastern Merced County, it's a relatively small region in the San Joaquin Valley. Our district dates back to the early

1900's, providing water to approximately to 2,200 local farms, and most of the farms are 50 acres or less and they're generational, people that have been there a long time.

MID is a nonprofit community-owned utility. In 1997, the District decided and began to provide retail electric service to our area. Since that time, we've connected about 6,500 residential customers and approximately 1,300 businesses. This represents, believe it or not, .02 percent of the California Energy use. We're very small.

Our public power is a very critical and needed asset to our community. All the benefits of our operation at Merced Irrigation District revert back to the community. By almost any metric that you choose, we are among the disadvantaged communities in our state. More than 25 percent of our residents live below the Federal poverty level. In comparison, the statewide poverty level is 15.9 percent. Unemployment in Merced County is almost double the statewide average, and Merced has one of the highest unemployment rates of any county in the state.

The public power we provide benefits both families and businesses by helping to keep the energy bills as affordable as possible. Our rates help draw businesses to our area, which are very needed, and to keep the ones that we've got there.

When Senate Bill 591 was enacted and signed into law, it was not done to provide a total exemption from the RPS goal, it was in fact enacted to allow us inclusion in the RPS goals.

In a region of some of the worst air pollution in the nation, I can assure you that we support the goals of RPS. Senate Bill 591 recognized that we face challenges both as a disadvantaged community and as a utility with some unique contractual and physical constraints affecting our operations.

We're proud that we are a financial supporter of the University of California's Solar Research Institute, which is located at our Castle Commerce and Aviation Center, and we're also proud that we serve that facility with electricity.

We want to also be part of the RPS Program, but as I've stated, we have some unique and special circumstances that require some unique and special considerations by the CEC. When it comes to RPS compliance, we feel that one shoe doesn't fit all and that consideration of the impacts of full compliance be taken into account in how it affects our local communities.

One key flexibility that would greatly assist MID And meet the clear goals of Senate Bill 591 would be to interpret Senate Bill 591 as a standalone provision that does not have the bucket requirements; this would reduce the overall cost of RPS compliance, while still allowing MID to invest the large majority of its RPS funds back into our community by funding or incentivizing distributed generation projects.

We ask that you respect the wishes of the Legislature and the Governor and you take any and all steps to assist us in meeting the goals of RPS, but we ask that you do it in a way that does not further handicap an extremely disadvantaged community. We ask that you do so in a way that will prevent RPS funding from flowing outside of our local economy, and we would ask that you do it in a way that recognizes that the very real physical and contractual constraints MID operates in our environment.

Thank you for your time and your consideration.

MS. GOULD: Thank you. Justin Wynne, Merced.

MR. WYNNE: Thank you. My name is Justin Wynne. I'm with the Law Firm of Braun, Blaising, McLaughlin and Smith, and I'm here on behalf of Merced today.

So I just wanted to build a little bit off of what Don went over and then also we will be following up with written comments that will go into a lot more detail there.

First, I wanted to thank staff, I believe the provisions relating to the applicability section, particularly the 20-year averaging, I think that's appropriate, that's sufficiently long enough to address any extended drought periods. And then also the methodology for how Exchequer gets attributed to Merced. I think that's appropriate and that clearly meets the intent of the statute that this applies to Merced.

As Don talked about, the actual way that the structure that supplies to Merced, under normal circumstances would not generally have any impact, particularly since this is averaged over a compliance period. So I think we know for certain in the second compliance period, no matter what happens next year, or the rest of this year for hydro, there would be no impact to Merced under the current proposal.

It’s also extremely unlikely in the third compliance period that there would be any benefit either. We would have to string several very wet years together, particularly with the outlook of the current drought, it’s unlikely that that would happen.

I think the clear intent, as we discussed today, of SB 591 was to provide consistent, year to year relief to Merced. Unlike the provision related to San Francisco, I think this focused on the unique hydro circumstances, SB 591 spent a lot of time during the analysis and during the discussion focusing on the poverty circumstances in the region that Merced serves.

I also think that it’s helpful to look at some consistent statutes, one that we’re looking at is a 2014 Bill, AB 2672, and that added Public Utilities Code Section 783.5, that directs the

CPUC to consider alternatives that would increase access for affordable energy in disadvantaged communities within the San Joaquin Valley. That includes Merced.

I think that we can think about these bills as having similar purposes, the Legislature is focusing on this region of the state that has suffered from extended economic disadvantaged circumstances, and it is focusing on lowering energy rates and then also providing the opportunities within the community for new energy resources.

As you're going through and implementing this, I think it's helpful to look at some of these consistent statutes to get an idea of the overall purpose that the Legislature had.

So one of the key things that we've discussed today is that I think it's clear from the legislative language, from the statutory language, that SB 591 was intended to apply on an annual basis. One subdivision (K), expressly states that it applies to annual retail sales. And then there is no reference to Subdivision (B) that describes the compliance periods, and in contrast if you look at the Subdivision (I that deals with purpose, special, retail sales calculation methodology, they include an express reference back to subdivision B, so I think the clear purpose was that that apply over a compliance period basis. That's not found within Subdivision (K), it's also not found within the Subdivision that applies to San Francisco.

And sort of already mentioned, if you apply this on a compliance period basis, I think it's going to lead to results that are clearly in conflict with the intent of the statute. So, for example, if in 2016 Exchequer produced more generation than the entire load of Merced, completely over their load, there would still be no impact to Merced. And so I think particularly when you look at the express language "annual retail sales," that's outside the intent of what the Legislature was looking for.

And then I know in the ISOR there was a discussion about the administrative difficulty of applying this on an annual basis. One, I'm not sure that should be a driving basis for how the statute is interpreted, but I think the way that you've implemented this with a 20-year averaging methodology would make it extremely unlikely that

that would happen just based on -- I ran some rough numbers. I think even if we had extraordinary drought conditions for the next five years in a row, because of the 20-year averaging, SB 591 would still apply to Merced, and so I think it's not going to be the case where on a regular basis they're popping in and out of applicability of this.

Because it creates an annual obligation, I think it's reasonable to interpret this, similarly to the San Francisco provision, as a standalone provision that doesn't include any reference to section 399.16. The ISOR mentioned that there was the provision that says that their obligation, shouldn't it be above what would otherwise be required? And I think there's some analysis in the legislative history looking at, like you could have a situation where Exchequer produced 20 percent of their load, and they shouldn't have an 80 percent RPS in that year. So I think it's just controlling for that very unlikely circumstance that would be outside the clear intent, but that's not itself an express reference to 399.16.

Similar to the situation that San

Francisco finds itself in, because of the unpredictable nature of hydro, one year could be full load, the next year could be very little. It makes it very difficult to do procurement for Bucket 1. Typically if you’re going to get better prices on Bucket 1, you would want to look at like a 20 or 25-year contract, and even the way you’ve interpreted the excess procurement rules, you’re severely punished if you’re doing short term contracts.

And then also, because of the unbundled versus bundled requirement, if you had already procured generation, and then you suddenly found out you didn’t need it, you’d be extremely restricted in your ability to sell that off.

So similar to San Francisco, they would have a lot of difficulty because of the variation in hydro doing long term planning. Unlike with Bucket 3 and also focusing on distributed generation, those problems don’t come up because you can generally do short term contracts for that, and if it’s structured for DG with their customers, that would be supporting other purposes, as well.

The ISOR also mentions that the San

Francisco subdivision expressly states that it uses the phrase “to procure eligible renewable energy resources, including renewable energy credits.” And there was a focus on the fact that there was reference to renewable energy credits in that subdivision and not Subdivision (K). The thing I would point out is that phrase is actually pulled exactly from Subdivision (A), so 399.30(A), uses the exact same phrasing of “eligible products from eligible renewable energy resources, including renewable energy credits.” So I think that’s just the general phrasing to describe renewable procurement and not signaling something unique within that phrase that, by not including it within Subdivision (K) has a significant difference.

So the last thing I would mention, just building off of one of Don’s final points, is that I think interpreting this bill without the portfolio balance requirements is fully consistent with the intent of the bill because, as Don was describing, they have certain Balancing Authority restrictions that would prevent them from building utility-scale generation within their geographic region and because of the general treatment of distributed generation as bucket three, they wouldn't be able to focus their RPS procurement funds within their community, that wouldn't be an option for them. Without the portfolio balance requirements, they would be able to, and I think they would commit to, the vast bulk of their RPS funds would then be turned around and focused on distributed generation, giving direction that is a primary means of compliance, and that meets the goal of reducing particularly the customers that would be taken advantage of that would have reduced bills, and then it would be creating jobs and economic benefits within their community. And I think that's fully consistent with what the intent was.

So again, we'll provide more detailed comments and then we're obviously available if you have any questions. Thank you.

MS. GOULD: Thank you. Okay, Mark Hendrickson, Merced County.

MR. HENDRICKSON: Good morning. My name again is Mark Hendrickson. I'm the County's Director of Community and Economic Development, which is to say I'm responsible for the County's economic development and business development and land use decision making for the entire County of Merced.

Thank you very much for this opportunity this morning. You know, it’s been mentioned on a couple occasions already, you know, Merced County has historically faced some very significant socioeconomic challenges. Historically, we’ve been very driven, our economy has been very driven by agriculture, but if the truth be told, our economy and our community is, in fact, changing.

While we still have chronically high unemployment, we are seeing some success. I will highlight a couple things just for you this morning. Castle Commerce Center, which is a former military installation that closed in 1995, just as an example, we today have about 95 leases, a couple thousand employees, and we’re seeing some fairly significant growth in development.

I want to highlight just two or three of those businesses that have come to Castle just in the law few years, which include Google, which now operates multiple projects at our site. We have an existing tenant at Castle who, in partnership with Boeing is going to be launching a simulator facility here, a multi-unit simulator facility here in the next few months, and then most recently in the last couple of years we were able to bring in overhead crane manufacturer to the area which, upon coming to Merced County, initially promised about 25 new jobs to the community, but after Year 1, had about three times that number. I highlight those three examples because if it were not for our partnership with Merced Irrigation District, those opportunities would not be coming to Merced County.

In an era, I believe, when we have fewer and fewer economic development incentives, and I think we're all very well aware of the demise of redevelopment agencies and enterprise zones, one of our last economic development incentives, I believe in our area, is through our partnership with Merced Irrigation District. They, by virtue of their ability to provide lower cost power than, for example, their investor-owned utility counterparts in the region, we are able to use that as both an expansion, as well as an economic development retention tool.

Just simply stated, going back to the earlier point, we are very hopeful that as you move forward, that you will do anything you can to assist our community by providing as much flexibility as possible to Merced Irrigation District as a part of their effort to maintain affordably priced power. Again, for us and in a community where we do have some fairly significant challenges, we need all the help that we can get and I think that, again, were it not for Merced Irrigation District and our partnership with them, we would be in much worse shape than we are today.

So with that being said, again, thank you for your time and, again, I'd appreciate anything you can do to help Merced Irrigation District respectively, thank you.

MS. GOULD: Thank you. Vinton Thengvall, Label Technology, Incorporated.

MR. THENGVALL: Hello, good morning. Thank you for letting me present this morning. My name is Vinton Thengvall, and I'm the CFO at Label Technology, Inc. We're a mid-sized business in the community of Merced and among those who benefit from MID's electricity. We are a label and packaging manufacturer. We use plenty of MID power to run our printers and laminate equipment.

Our business began with three people working out of a garage in 1986. We have grown to a $35 million corporation with more than 120 employees. We became 100 percent employee owned in 2007.

In a community like Merced where every job counts, we represent an enormous success story; we don't take that for granted, as a result of the dedicated employees, loyal customers, and vendors that provide reliable services that has allowed us to grow.

The affordable electricity provided by MID is a large part of that story. Over the four plus years that we have been served by MID, we have had nothing but exemplary service. We know that when we have a question or are in need of any kind of assistance, we're literally calling a neighbor down the street. We know that they have an understanding of our needs and are there to do whatever it takes to make sure we are successful.

I respectfully would like to request that you take any steps possible to help our local utility with this matter. Again, their affordable rates have been an instrumental part of our success. Thank you very much.

MS. GOULD: Thank you. Luis De La Cruz, Between Friends.

MR. DE LA CRUZ: I would like to yield to my wife, Irene De La Cruz.

MS. GOULD: Okay, thank you. Irene.

MS. DE LA CRUZ: Thank you, babe. Hi, my name is Irene De La Cruz. I'm the owner and publisher of a publication called *Between Friends, Entre Amigos*. We have a little bit over 21,000 readers in Merced County, it's in English and Spanish, and we focus on Latinos and Hispanics in a very positive note. So thank you once again for allowing me to speak today.

My husband and I, you know, grew up working in the fields in Merced County. We know what poverty is, we lived it, and so that is one of the reasons why I'm here today. What we do is we now work to provide a voice for those that otherwise wouldn't have one. We deal with a lot of people in Merced County because of our publication, and in the community work that we do, we see a lot of people that are, of course, in need. You can see the lines of people standing for what's called the brown bag, which is food that's given out to seniors and then the USDA also that gives out bags of food, and it's very heart wrenching to see them line up. They come at like 4:00 in the morning, you know, line up at the community hall just to make sure that they get a bag of food. So it's very, like I say, heart wrenching to see the line get longer and longer.

Now today you've heard a lot of numbers about Merced being a disadvantaged community, you know, 25 percent of our community lives below the Federal Poverty level, we have 16 percent unemployment and a median household income of nearly half of that of the state average.

But I want to share with you that there are human beings behind all these numbers. Like I mentioned before about these people standing in line for food, we have people that come to us to ask us about, you know, "Do you know where I can get a job? Do you know how I can get some food?" That kind of thing. Five to 10 dollars paying for, you know, an increase in your utility bill, it makes a lot of difference for people. Beans and rice can only go so far, for $10.00, you can get spaghetti and something that will feed your family, so it’s very crucial, it has a great great impact on the people in our community that is so disadvantaged.

So I don’t claim to understand the policy issues behind, you know, being discussed here today. But I do understand poverty and I understand the value of a dollar. The goals of the RPS Program, as I understand them, are commendable, but from what I’ve seen, the RPS Program results in our impoverished community subsidizing renewable energy projects and jobs in other communities, and that’s simply not right.

I understand everyone in this room has difficult decisions to make, I also understand they are often times not easy answers. However, as you discuss these important issues, I want to ensure you understand that real people living in real poverty are affected by the outcomes of your discussions. I know it’s a tough position to be in; the people before you today from MID are not here out of greed, they represent a local public agency. I know wholeheartedly, and I believe they are here for the same reason, that they come to the poorest parts of our community to hand out balloons and coloring books to children who have, you know, little else. They are here because they care about the wellbeing of our entire community, from those who are employed to those who are hoping to become employed.

I would like to respectfully request that you don't simply take my comments and others into consideration. With greatest respect, I am asking that you go beyond that and provide our community with the help it desperately needs. We need every dollar we can keep in our community, and we need every job that can be created or sustained in our community.

And I just want to let you know one last thing, is that I think the bottom line, all we are asking for, is fairness. So thank you once again for allowing me to speak today.

MS. GOULD: Thank you, Irene. Luis, would you like to speak, as well? Okay, thank you. Steven Kelly.

MR. KELLY: Good morning. My name is Steven Kelly and I am with the Independent Energy Producers Association.

And I wanted to speak on a slightly

different issue which is kind of the necessity of making sure that your regulations that you finally promulgate are clear and concise, and I'm happy to hear that you're going to be spending some time on these Regs because the language that I've seen and read today, I think is not meeting the standard that we want. And let me tell you what I'm talking about particularly, is the section in the Express Terms that deals with, for example, bundled product and why it matters.

Why it matters is because the language that you promulgate here is going to impact what the Public Utilities Commission does, and it actually has spillover effect in how WREGIS tracks things. We need to be very clear. Recently I've had an opportunity to read comments from the PUC in a proceeding in which I was not engaged, which was the Net Energy Metering proceeding, and I was struck by the fact that the language people are using is awfully loose and messy; for example, DG, I've heard it described today, DG as I understand it is defined as anything that is less than 20 megawatts, interconnected at the distribution and transmission system or behind the meter. It's not simply behind the meter. We have to get the language more precise so that we know what we're talking about. And when it comes to regulations, that's absolutely critical.

And I want to talk to you about the paradigm that I understand is in place today and contrast it with the language that you've used in your bundling description under the Express Terms, to describe what I think is a disconnect.

As I understand where we are today, we have essentially renewable energy is of two types, it's either load modifying, i.e. behind the meter, or it's supply resources. As a supply resource, you're either going to be a retail product, or you're going to be a wholesale product, there's no any other alternative to that. And this is why metering is so important, because metering is necessary to make sure that whether it's retail or wholesale, it's accurately metered, you can avoid abuse, and double-counting, in terms of meeting compliance with RPS. So metering is critical for those types of resources.

Ownership is essentially defined by rule now, behind the meter is a resource that is owned by the, as I understand it, the homeowner, for example, if it’s rooftop PV, but that’s a load modifying resource. Sales Agreements define the relationship for the remainder, for retail and/or wholesale. And this is important because then it affects how you define things in terms of the bundling concept, or the buckets. Who owns it? At what point do they have ownership? And when does the environmental attribute separate from the ownership? For behind the meter resources, how is it retired?

I think there’s a fundamental lack of appreciation for the need for clarity across all the Regulatory Agencies, and among stakeholders on the paradigm in which we’re operating, such that we end up with regulatory language that is squishy and mushy and is not consistent across the agencies. And I think that is a huge problem that we need to fix now. So I appreciate the fact that you folks are going to spend some time on this. I read the bundle description in the Express Terms and I did have some concerns, I think it fosters double-counting, for example, which is something I’m very concerned about, and so forth, and it’s not clear who is going to own stuff. So we need to work on that.

And the reason this matters is clarity and is because the entire RPS Program, from the get go, has been built upon policy makers, but more importantly public confidence that what they’re getting, or what they’re paying for is what they’re getting, i.e., an eligible renewable resource. That’s why metering is so essential in this whole program, to keep the public confidence there that they’re getting what they pay for.

And if we undermine that integrity at the metering and undermine the integrity of the claim for an RPS resource, we risk undermining the entire program and the public’s confidence in this. So that’s why it’s important and I’m pleased to hear that you’re going to spend some time on this, I’d like to work with you on this, we can provide language, but if you’re going to have a workshop or another process, I’ll wait until then. But I think we all –- and we need to draw the PUC into this, as well.

MR. HERRERA: Quick comment: you know, these rules would apply to POUs, not to retail sellers, so obviously the CPUC has their own rules, we work with them behind the scenes to make sure that our rules are consistent with them, it makes sense that there be consistent rules across the board. I wanted to leave you with that thought, to say that what we're doing here will affect POUs because these are POU-related rules, and the CPUC may disagree with aspects of these Regulations.

MR. KELLY: Yeah, I get that, but I think there's a paradigm here that we all need to agree to generally because from the developer perspective who is trying to sell this stuff to load serving entities, it really doesn't matter and, as you develop these things, you need to know. And there ought to be consistency to the extent that we can achieve it between the POUs and the IOUs on basic concepts, set aside treatment on the hydro issue, or whatever else, just basic stuff. So, thank you.

MS. GOULD: Anthony Andreoni, CMUA.

MR. ANDREONI: Thank you. I'm Anthony Andreoni from the California Municipal Utilities Association. First off, I want to thank the CEC and ARB jointly hosting this workshop, I think this is a move in the right direction that you all are working and coordination as you go through these amendments. I just have a few overview points I want to make and we will certainly follow-up with written comments to the CEC.

First off, this is the first issue I'll talk briefly about, is an issue that we have brought up in the past. It's dealing with how Product Content Category or PCC1 for DG is dealt with. You've already started to hear a little bit about this. Our concern with the proposed definition on bundled is that it's too narrow. It still lacks authority and consistency and clarity as required by the Administrative Procedures Act, or within State Policy and the direction of the electric industry.

By treating behind the meter as -- behind the meter I'll just refer to as DG, in this case as PCC3 -- the Energy Commission is limiting the ability for DG to be no more than 10 percent of a POU's grandfathered RPS procurement. And that's important. For many POUs, this would mean that DG would account for a small fraction of the total RPS procurement.

It's really, to look at it even broader, it's inconsistent with the Governor's 50 percent renewable goal, which calls for more distributed power and expanded rooftop solar. I mean, that's something that we are working on and looking towards trying to figure out how everybody is going to be able to meet that.

It's also, from what I can tell looking at the ARB Scoping Plan, a little bit inconsistent because that also encourages onsite DG. And obviously the Governor's policy is really supporting a lot more DG on the grid.

There really needs to be consistency, again, I'm happy to see that both the ARB and CEC is here, between both Regulatory Agencies on those policies.

Also, as you look at PCC3, the Bucket 3 RECs, they're not worth as much as what they are as a PCC1. This means that the customers that own DG facilities are being compensated at a level far less than generated, generation that is located far from the load, or even out of state, so this seems to be a little inconsistent, again, within RPS.

We recognize that this is a very complex issue that will require substantial consideration. However, the CEC should not further restrict the ability of POUs to structure transactions with their customer to provide PCC1 from DG facilities.

Moving to my next issue, we do support what Merced has already mentioned. The implementation of SB 591, as you heard also from Senator Cannella’s Office, Merced serves one of the most economically disadvantaged regions in the State. I briefly went over your economic valuation, you do provide some cost evaluation in your presentation, you provide some cost number basis for meeting some of the changes in the rule, but I don’t really think, just in the first review that I’ve seen, that you really encompass the economic impacts from local governments that are going to be impacted from the changes that you’re providing and suggesting. The economic impact really needs to be looked at a little closer. Some of the values and some of the assumptions you make don’t always necessarily align with what our members are going to have to do to meet the requirements, and so I think that does need to be looked a little closer.

I recognize there are provisions in the rule for alternative compliance, but in reality we're really trying to make sure that this can be implemented and it doesn't disadvantage the community of what's going on currently. The clear purpose of SB 591 was to provide MID's customers with relief from the costs of RPS, and the way it's written it would only provide relief during very wet hydro years.

So we just recommend that you should interpret SB 591 to provide MID with sufficient flexibility, such that it can invest in its RPS funds into the community.

The next item I'll focus on is just excess procurement. This has been one that we've talked a little bit in the past. The existing excess procurement rules are fairly restrictive, they virtually limit, no POU can use them for any non-grandfathered procurement; instead, the POUs must rely on the 36-month window for retiring RECs, the option is administratively more complicated, and puts the procurement at risk if an inadvertent error results in the 36-month window being exceeded. There's really no clear rationale for severely restricting access procurement and it serves to add unnecessary administrative cost to the POUs and, again, that adversely or unnecessary administrative cost should probably also be looked at a little closer within the economics framework that you're looking. We will continue to provide more detail, as I mentioned earlier in our written comments, we do request that CEC considers modifications such as this one where the technical reading of the statute adds administrative costs and burden. And the CEC must ask whether the benefit or policy purposes are served to justify those additional costs.

The last issue I'll just highlight on because I know ARB spoke a little bit about enforcement, we do expect since the beginning of this rule that should there be any consideration of a fine or an issue after looking at verification, that the CEC has to consider moving it over to the Air Board, that we have the ability to work closely with the Air Board at that point and recognize that currently, legally, the ARB, the way this is set up, has to meet that obligation, those statutory obligations consistent with the authority set out in law. So until there is any changes, certainly under current legislation or proposed legislation, we really do want to work closely with the ARB to make sure that you're not only tuned in early, but we have the opportunity to continue to talk about those issues. So we will -- we do have a few other areas I'm not going to cover right now that we will add to our written comments to you. But, again, thank you for your time and we look forward to working more with you on this effort.

MS. GOULD: Thank you. John Pappas, PG&E.

MR. PAPPAS: Thank you for the opportunity to speak before you and thank you to both the CEC and the ARB for holding this workshop. I'm John Pappas from PG&E and I work on Renewable Energy matters. And first of all, I wanted to commend you on the work you've done so far on the changes to the Regulations and appreciate your consideration of our July 28th comments, July 28, 2014.

PG&E intends to file additional comments on the proposed changes and I just wanted to file a few areas that we have some concerns with here. One area is an area that Steven spoke about and that is the definition of bundle. We believe that the CEC should not classify POU-owned behind the meter generation as bundled, that that would create disparate treatment between the RPS responsible entities among the state, disparate treatment between the ones obligated to the CEC requirements, and those obligated to the CPUC, and that they should instead get classified as Category 3.

The second area is the definition of dynamic transfer and the requirement that an hourly schedule be included in that. We do not see any such requirement actually in the legislation. There seems to be a distinction between hourly deliveries and those that are subject to dynamic transfer and that simply having a dynamic transfer agreement should be sufficient.

And then the last area that we'll comment on is in terms of the implementation of 591. We believe that Regulations must be consistent with the law and specifically that MID must receive the generation from its facility in order to qualify for the counting exemption, and also must demonstrate each and every year that has served 50 percent or more of its sales with large hydro in order to qualify.

So I appreciate the opportunity to comment and, again, we'll be filing written comments.

MR. HERRERA: John, could I ask you a quick question concerning behind the meter DG. So you indicated that the rules need to be consistent, Energy Commission's rules, CPUC's rules, and I know we've talked to a number of POUs that own behind-the-meter DG, so to speak, and they use it perhaps for their own purposes. Is PG&E in a similar situation? Do you own a lot of DG like that?

MR. PAPPAS: No, we do not.

MR. HERRERA: Okay. Thanks.

MR. PAPPAS: Thank you.

MS. GOULD: Thank you. Rachel Gold, LSA.

MS. GOLD: Hi. Good morning. Rachel Gold. I'm the policy director for the Large Scale Solar Association. And I very much appreciate the opportunity to comment this morning. I just wanted to speak on a couple of issues, one that Steven already mentioned. I wanted to also weigh in and express our concern with the changes to the definition of the bundled product. Our concerns are principally that this change doesn't appear to address or account for the disconnect between counting behind the meter generation differently for the POUs in this case than for the retail sellers or other onsite load that may be used in a similar manner with other transactions. And while we recognize that the CEC is putting forth regulations for the POUs, those changes have real impacts in the market in terms of the kind of signals that developers are getting, the kinds of transactions that are being developed, and certainty for both existing contracts and how the market is going to move forward.

So those are some of the reasons we think it's really important to clarity that language and to have a very thorough discussion of why and how this change retains integrity of the current system and ensures there aren't double-counting of those RECs. And this is principally because, for most of those situations, that behind-the-meter generation would already reduce the retail sales numbers, it's the basis of the requirement for the RPS obligation. So I think that really needs to be addressed and we look forward to working with you on making adjustments to that definition.

So the other piece that I wanted to mention, and we submitted some comments, initial comments yesterday just to highlight this for all of you, is that we were concerned when we saw the change of the averaging of the hydro generation, and we certainly understand that the change due to the extreme drought is resulting in many changes potentially for POUs that might have otherwise met an exemption, but on the face of this, it appears that we're changing a regulation midstream in the middle of the compliance period to ensure the same result, and that is problematic. And so I'd love to hear more and discuss with all of you some more of the rationale behind that change and why it makes sense in this case. I think we really want to see the RPS be both productive and effective, and that we are making real progress towards our collective goals.

MS. GOULD: And I can touch on that briefly. We were looking at changing the averaging period and this is for San Francisco from seven years to 20 years. The seven years was based on an averaging period for retail sales for I think it was PWRPA and Eastside, and kind of use that as something to hang our hat on, a number to hang our hat on, for averaging for San Francisco's hydro sales just to qualify for the exemption. It made sense to have some sort of averaging because of the sort of fickle nature of hydro. But the 20 years, we subsequently realized was the basis of the incremental hydro baseline and the RPS Eligibility Guidebook, and we felt that that was a more appropriate number to base our averaging period on than the seven-year retail sales averaging for PWRPA. So I think that was the genesis of it. It was to find a way to average it and a way that was consistent with current practice, and kind of accounted for the up and down nature of hydro generation.

MR. HERRERA: Yeah, I can add some more to that. You know, additionally in the case of San Francisco we did obtain information from San Francisco on their Hetch Hetchy productions and found that that number in the statute, the 67 percent, was consistently met and so changing it from seven years to 20 years in the case of San Francisco, in our view, didn't look like it made a big difference. But having a requirement for one POU that measured compliance with a condition in the statute based on 20 years versus seven years did not make sense.

And we also, when we looked at the situation for Merced Irrigation District, recognized that there was the intent in the statute to provide some relief to Merced, so we didn't want to select an averaging period for them that resulted in no benefit at all. So for consistency purposes, and based on our reading of the statute, SB 591, we thought 20 years was the appropriate averaging period. I mean, if you think that a lower averaging period makes more sense given the language in the statute, I would encourage you to provide comments to that effect.

MS. GOLD: Okay, thank you. And I appreciate the explanation. Thanks, that's all I have this morning.

MS. GOULD: Thank you. Susie Berlin, NCPA and MSR.

MS. BERLIN: Good morning. Susie Berlin for NCPA and MSR Public Power Agencies. I have a couple of questions and so rather than comments, so it's a workshop, I was hoping you guys can enlighten me here.

With regard to the revision in 3206(A)(1)(a)(iii), there's a limit on the applicability of an extended contract. If you have a contract for more than 10 years and you extend it, and for less than 10 years, you're not allowed to count for excess procurement what is for less the extension period. And I was wondering if you could tell me what the objective is there if we already have a contract for more than 10 years and it already meets the goal of encouraging long term procurement, so extending that same contract for a time, maybe even as a stopgap measure to continue development of larger long term projects? It doesn't seem that it's consistent with the statute to penalize an entity that had already entered into a long term agreement in the first place.

MS. GOULD: So when we were looking at the intent of the statute, we felt that it was to encourage, you know, going forward, long term procurement, and when we thought about having a 10-year or greater contract in place and then potentially adding little increments, maybe a year at a time, or something like that, we didn't feel that was consistent with the intent of the statute.

MS. BERLIN: Okay, thank you.

MR. HERRERA: Can I just ask a question back to you, Susie? So in that case if you have a long term contract greater than 10 years, and now you're looking at amending it, I mean, would one of the options available to the POU be extending it for a longer period, for another 10-year period? Or --

MS. BERLIN: It could be, or it could be that you're developing another long term resource that didn't come on line as fast as you wanted, so you just need to use this existing resource for a few more years or something less than 10, so that as a stopgap measure, for example. So there are myriad scenarios that can come into play that would justify and warrant a shorter extension.

With regard to 3206(E), the new provisions on applying optional compliance measures, can you give me an example of how you think, just an example of how 3206(E), what that would look like.

MS. GOULD: I forgot which one that is off the top of my head.

MS. BERLIN: I’m sorry, that’s applying the optional compliance measures for delay of timely compliance, or a cost limitation for a proportion.

MS. GOULD: Right, right. So the existing language only sort of envisions or has language for a full waiver of compliance. And we wanted to make clear in the Regulations that a POU could, if it only has rationale for a portion of its shortfall, it would be able to submit a request for waiving a portion of that rather than the entirety. So this is to allow for a POU to request some portion and, if it doesn’t meet the entirety of the shortfall with a delay of a timely compliance condition or a cost limitation, that it would be allowed to ask for some lesser amount to be waived.

MS. BERLIN: Okay, thank you. 3207(C)(1)(i) is the new requirement -- sorry, too many post-its -- for the POU to report the energy consumption. What do you envision that reporting looking like beyond the new form? Or can you explain a little bit more about what the reporting would look like?

MS. GOULD: So I think we asked for a

description of it, so I think it would have to be -- we might add a field to the reporting forms that include a place to put an energy consumption number; it also might just be a narrative backed up by any documentation you may have on the POUs on energy consumption. So we wanted to have that information to support our verification of retail sales numbers because we were looking at different retail sales that POUs were reporting, they didn't always match what was reported to EIA, oftentimes that was because of the POU's own energy consumption, and we wanted to be able to have those numbers so that we could do our verification comparisons.

MS. BERLIN: Are you going to be providing information about what that reporting is going to look like in advance so we know what needs to be done with -– I mean, do you anticipate supplementing that proposed amendment to clarify? Because that just seems a little amorphous now for our purposes.

MS. GOULD: I think these Regulations won't be effective until October, so it wouldn't apply to the reporting period that's coming up in July, so it wouldn't really have an effect until next July and we will have more direction available for the POUs before then.

MR. HERRERA: And if you have ideas on how you can report that information in a way that minimizes the amount of work POUs have to do, that would be great.

MS. BERLIN: I think Angie raised a good point about reconciling different reports that are used for different purposes, and now they're being turned around in some instances and used to verify something that they were never intended to be used for, so I think that that's a problem. Maybe in the larger reporting what information you already have, what information you additionally need, it's a side issue that overlaps quite a bit into the RPS.

With regard to the 1240 and the enforcement provisions, we also appreciate the Joint Workshop, knowing where the CEC and the Air Resources Board is coming from, but I think it's important, absolutely imperative that for purposes of this point in time, we realize that there are separate and distinct roles that there may be pending legislation, but that legislation is not the law right now, and we need to move forward with the roles that each agency has under the regulation and, in particular, extremely concerned with the role the CEC is placing them self into by asking in the answer to a complaint for information regarding mitigating factors. First of all, the answer to a complaint is for noncompliance and the mitigating factors go to the extent of a penalty, so it is on its face inappropriate for you to have to assume your guilt when you're answering, and then go forward and move on to this next step, and I don't think that they're appropriately part of that vision.

Second of all, the role of the CEC in reviewing compliance is not based statutorily on review of any of the mitigating factors, so with or without them, the CEC has to come to the same conclusion because that's what's in the statute, so it's inappropriate for that to be in the CEC's Regulation.

And then finally, if the CEC is going to make a penalty recommendation, it seems like they could do so based on the information that they have at hand, but application of the mitigating factors is still a role for the Air Resources Board and not for the CEC, and the CEC is making a determination of compliance which is exclusive of review of those mitigating factors. So any penalty recommendation would be based exclusively on comparability to the CPUC's Regulations, but the statute requires that when the Air Resources Board makes a final determination, that's comparable with that, but also consistent with the authority that the Air Resources Board has.

So I'm really concerned here with what I see as blurring of the roles of the agencies and essentially cutting the Air Resources Board out of their statutory authority to apply their penalty metric when looking at whether or not a penalty is appropriate if there is not compliance. So those are all my comments for now.

MS. GOULD: Thank you. Okay, Tim Tutt with SMUD.

MR. TUTT: Good morning. I am Tim Tutt representing the Sacramento Municipal Utility District, and obviously I'm going to have some comments on one of the big issues that's been discussed today, the definition of bundling and how that's been changed in the Regulation. I think I'll probably spend more time talking about that than anything else, so I wanted to get a couple of other things out of the way first. And the first is the provision that you've added to clarify what happens with contract amendments in the small group of resources, 3202(A), those resources that were signed before June 1st, 2010, but weren't eligible at the time, presumably. We appreciate the clarification there, but two things, we think you've gotten that clarification a little bit wrong in that you tie the change in the resource from sort of a not grandfathered, but unclear status, to a categorized status, to the length of the term of the original contract.

So for example, somebody could make a change in the contract that increases generation, but keeps the same term, and it wouldn't make any change in the categorization. So we think you should change the clarification to say something like the resource or the contract is re-categorized when the original terms of the contract no longer apply, something like that, so that somebody could say, you know, from this point forward, our new contract is now categorized, or our resource is categorized. If they increase the generation with capacity but not the term, then they would apply from that point forward when that increase occurs, and so on.

And the second point is that you say that this is consistent with what you've written for 32(A)(O)(2)(a), the much larger set of grandfathered resources, but I would point out that the language is different, and the original language, the original clarification of the amendments doesn't provide a lot of clarity about what happens in a variety of circumstances when that larger set of contracts changes. So what I would recommend is, again, and we can submit language, consider the clarification you're providing for 3202(A)(3) and make the same change for 3202(A), the earlier language so that it is consistent and everything is as clear as possible for that.

The second issue I'd like to raise is the 3206(A), that people have talked about it as excess procurement, the question of what happens with amendments to contracts and how they might affect the excess procurement calculation, depending on the length of the amendment. We understand that you probably had to clarify something there, the original law just said 10-year contracts, or less than 10-year contracts, it didn't say anything about amendments. We think that you've probably found the most restrictive, from the perspective of the market, way of clarifying that, I don't think that really should be your mission, I don't think it is, but that's where we think you've ended up. So we would recommend taking another look at that and, again, we'll submit language that suggests maybe a different way of clarifying that, that provides the clarity to the market, but doesn't unnecessarily restrict cost and restrict the market for procurement of these resources and making amendments. As an example, you might have a very good deal that says somebody says, "We want to increase the term of this contract by five years," it might be a 15-year contract, but we can only do five years because after that somebody else has our product. You'd have to turn that deal down. And why would you want to restrict the market that way when you already have a 15-year contract?

Now, to the question of the bundled definition, we do appreciate the movement here to add a certain, I think, amount of resources to the concept that this can be called bundled. As you know, we've argued in the past for a much more extensive move and we will continue to ask that you move much more extensively to looking at these resources that are interconnected within our distribution systems, as effectively bundled products, in much more circumstances than you've suggested.

With respect to clarity, I don't see anything in the changes you've made that says the words "behind the meter." It merely says "POU ownership" and "electricity consumed onsite." That could be behind the meter or a resource that's onsite that sells all the electricity to the POU, and the POU sells it all back. That could also be considered electricity consumed onsite, so I think the definition is unclear as far as it goes. And then I would point out that ownership is not a real good factor or component to base this decision on. If it's owned by a POU, and it's selling all of its electricity, or is contracted by all the electricity, it's not net metered, and then the POU sells electricity back to the customer? In our minds, that's no different than if it's owned by a third party or a customer and it sells by contract all of the electricity to the POU, and then the POU serves the customer. There's absolutely no difference in the real world between those two situations in our minds. So we don't understand why you made the distinction based on ownership, even though we appreciate the fact that you've expanded this a little bit. Obviously we'd like to go a lot further and I would point out that there's a big difference between, as we've said before, selling electricity, buying electricity from an out-of-state generator, and selling it back to that generator right away so that that generator then sells the electricity to someone else. And under the new RPS, what that kind of transaction is called is a Bucket 2 transaction in many ways because it's either unbundled RECs or Bucket 2, but there's no Bucket 2 for instate generation, you're constraining all instate generation where there happens to be a generator on a customer site to Bucket 3, and we've talked about how that is eventually going to really sharply constrain the use of Bucket 3 resources for the RPS.

With respect to questions of double-counting or integrity of the RPS and metering issues, with all due respect to my good friend Steve Kelly and my new friend Rachel Gold, I don't think those issues are pertinent here. Nobody is talking about changing meters here, your requirements still have a plus or minus two percent metering requirement. Nobody is talking about figuring out how to avoid double-counting or whether there is double-counting here. The best way to avoid double-counting is to get resources tracked in WREGIS, these resources have to be tracked in WREGIS, so to be part of the RPS, there's not a double counting issue here. To the extent that you're talking about the load modifying effect of a behind the meter resource, it has that additional small impact, it's not the same as double-counting, it's just an additional factor for behind-the-meter resources that can be accommodated in the RPS by considering the generation of those resources as retail load. It actually does serve retail customers within California. And we suggested this before, we don't think that the fact of the resources are behind the meter should prevent them from participating in RPS, and in fact it doesn't.

They do participate in the RPS despite the behind-the-meter load modifying aspect, they already do. So we think that those issues aren't pertinent here. What's really pertinent is the fact that these resources are attached or interconnected in our distribution systems, serve the retail load of our customers, and that electricity meets all the requirements as far as we can see of product content Category 1 resources.

The fact that the resources are bundled or unbundled in a net metering situation, we've had that dispute, but if it's a situation where the contractual relationship is that no matter where the resource is located, all of the energy is sold to the POU and the POU serves that customer. We don't think it's at all similar to having the electricity sold back to a generator, that's not what's happening. Electricity is being sold to a customer. It's serving retail load. So, thank you.

MS. GOULD: Thank you. Tanya De Rivi, SCPPA.

MS. DE RIVI: Good morning and thank you very much to the Energy Commission and Air

Resources Board for holding today's workshop. I'm Tanya De Rivi, the Director of Government Affairs for the Southern California Public Power Authority. I wanted to reiterate some of the comments that have already been said by our fellow publicly owned utilities and we'll also be submitting written comments that go into further detail on some of our priority issues for the RPS Enforcement Procedures, as well as the Penalty Proceeding.

First up on the distributed generation issue, we again believe that all distributed generation should be counting as a Bucket 1 resource. We still are perplexed on why it is that California solar should be valued less than out-of-state wind resources under California's own Renewable Portfolio Standard. We don't think that the reverse should be the State's intent.

At a minimum the excess energy paid for by utilities from distributed generation customers should be counted as a Bucket 1 resource, and we are encouraging the Energy Commission and state policies to expand renewable products to a broader market as the best and most cost-effective way for California utilities to meet the RPS.

Also wanted to broaden the discussion beyond the Governor’s and the State of California’s push for a 50 percent renewables target by 2030, so also consider both SCPPA’s comments, the Joint Utilities’ comments, which PG&E was a part of, as well as the Air Resources Board comments that were filed with the U.S. Environmental Protection Agency that recommended a modular approach for the Clean Power Plan that California recommended a modular approach like an RPS, for example, and that having overly restrictive RPS policies in California will make it extraordinarily difficult to try to sell other states like sunshiny states in Arizona and Nevada, for example, to participate in working with California on an RPS. So we will outline concerns we have with the definition of bundled outlined in Section 3201, the ownership metric, as has already been stated, isn’t the most correct and probably overly narrow restriction on how that’s being defined, such as if POUs use Power Purchase Agreements.

We’ll also be filing comments on the Optional Compliance Measure, Section 3206. We’re going to recommend that staff recognize natural and manmade disasters as an optional compliance measure, things like earthquakes, terrorist attacks, cyberattacks that may impact a publicly owned utility's ability to meet requirements. And under compliance reporting, we'll be recommending a modification on the documentation issue for PCC classification. We're also looking forward to getting some more clarity as NCP and MSR had already mentioned on the water pumping issue, it's overly broad right now and we would appreciate working with staff to help clarify that further.

We also wanted to reiterate comments that we have on ensuring that the Air Resources Board under the current law remain an independent and unimpeded process separately from the Energy Commission as they work forward on the RPS Enforcement Penalty Proceeding. We will be filing our comments by the end of the month, a few weeks early, and we'll be following up with you all if you have any questions on that. Thank you.

MS. GOULD: Thank you. Nancy Rader, CWEA.

MS. RADER: Good morning, I’m Nancy Rader with the California Wind Energy Association. I wanted to just first briefly agree with the comments that PG&E made on dynamic transfer and on SB 591, and also agree with the comments made by LSA and IEP on the bundled product definition, and I did want to expand on the concerns with the bundled product definition.

LSA raised the issue of double-counting of behind-the-meter solar because you’d be counting the reduced load that results from the solar, as well as the solar production that double counts. We believe there’s also another fundamental concern about double-counting that hasn’t been discussed today, and that relates to what the host of the system, whether it’s behind the meter or not exactly, whether the host of the customer sited system believes they are getting. Do they think they are receiving solar energy? Do they tell their friends and neighbors that their home is powered by renewable energy? Do they believe they are offsetting their own greenhouse gasses associated with their electricity use and even the use of their car? I suspect that they do.

Even if the system is owned by the utility, or if owned by the customer, if the contract allocates the RECs to the installer, what does the consumer believe? Has there been a clear disclosure that they are not getting solar energy? Are they given a choice in the matter? Does California have any consumer protection standards in place and, if so, does the utility have to show in order to count those RECs that the consumer protection rules have been followed?

Unless and until these kind of things are addressed, we don't believe we should allow any customer sited RECs to count as Bucket 1 renewables. Thank you.

MS. GOULD: And just, sorry, just a quick question. So would your concerns also go toward counting customer-sided DG as Bucket 3?

MS. RADER: Yeah, I think the customer protection concerns apply there, as well, actually. I hesitated a moment to say that because I haven't really thought about it, but I think the same would be true for Bucket 3.

MS. GOULD: Thank you. Abraham Alemu, City of Vernon.

MR. ALEMU: Thank you for giving me this

opportunity to comment. My comment relates to a request to add to the modifications concept that hasn’t been brought up yet. It has to do with the optional compliance mechanisms. We would like to request one of those modifications be to include regulatory delays. That request is to fault. The first thing is, when SBX12 became law, POUs were required, the governing bodies were require to come up with enforcement and compliance plans. The City did that and that was just a little bit sooner, I mean, ahead of the CEC regulation, so we went ahead and adopted the compliance plan and the enforcement plan. In that compliance plan, one of the provisions is regulatory delays were considered to be part of the mechanism as the option compliance plans. But when the CEC regulations were adopted, that concept, that provision is missing. The staff tried to implement these two regulations that were in the rules, one by the City Council, two, by CEC, it creates a problem to us, which rule, which decision do we go by? Do we go by the Council approved mechanism, I mean, plan? Or do we go by what the CEC adopted lately? That’s a huge problem. So for that reason, you know, for the sake of consistency, for the sake of alignment, we ask the mechanism be included as part of the optional compliance mechanism. The reason why that's important to the City of Vernon, as every one of you know, in the middle of the RPS implementation process, the CEC suspended the applicability of the rule to out of state biomethane as it relates to biomethane. That process, that moratorium, took roughly 16 months to be back, you know, to be active. So during that time period the contractors, the counterparts we had to deliver biomethane were not able to provide, to deliver the biomethane in time and that affected the City's ability to comply, you know, for comply fully with the compliance period 1. They were not sure if their biomethane would be counted back at 1 or, you know, back at 3, or nothing at all.

And the second factor was, there were some projects that were actually in the queue to be developed, but that 16-month process pretty much killed the financing option for those projects, so not only we got a lower volume of delivery when the suspension was lifted, we lost resources that would have delivered biomethane at our existing contract.

So what I'm saying is, you know, the issue is important to us, to Vernon, it meant it omitted the compliance period 1, RPS requirement or not, and above that, you know, the City Council looked at statute SBX12 and believed it was within our authority to include those compliance provisions. And for the staff now to try to implement the decision, we are at a loss, basically, you know, do we go by the CEC adopted Regulation? Or by the Council Decision plan? So for that reason we seek, you know, the modification inclusion of a regulatory delay as an optional compromise mechanism. Tanya brought a number of issues which we like, we concur with, one of them being the counting of behind the meter DG for compliance purposes. Just, you know, like any utility, we're being faced with questions of do we actively promote, you know, behind the meter solar, or not? If the value the entire customer basically is going to get is PCC 3, so that's been a real invest or not to invest issue for us, can we use public funds? You know, if it doesn't have that value? So we agree with the comments submitted by Tanya SCPPA. I plan to work with Tanya, you know, and include my comments when the SCPPA comments are provided later on. Thank you.

MS. GOULD: Thank you. David Kolk, City of Colton.

MR. KOLK: Good afternoon, or morning, I guess. I appreciate the opportunity to be here. I'm David Kolk from the City of Colton. Colton is a disadvantaged community in the San Bernardino area, it is dedicated to sustainability, both water, electric, and all aspects of sustainability. Colton faced an interesting issue. In 2005, our peak demand was 95 megawatts. Today, our peak demand is 84 megawatts. We've never recovered from the 2009-2010 economic downturn. But in 2007, Colton had already acquired resources to meet 120 megawatts of load. So Colton was in a position where any renewable purchase, or any type of purchase, just added to its surplus generation. That process will change in 2018 as a result of some of the environmental rules that have been going on in 2017, Colton's largest energy resource, the San Juan Generating Facility in New Mexico, shut down. This will take out San Juan 3 and approximately two-thirds of our energy. In anticipation of this, Colton has already been acquiring resources to come on line beginning in 2016 and 2017, even though it has to be shut down, San Juan 3, by the end of 2017. We don’t know when it’s going to shut down, nobody really anticipates that this unit will live until the end of the time period. And if you’ve seen the operation statistics of it, you know we would all prefer it would be shut down and burned today. When you have a coal plant that’s operating less than a wind fire capacity factor, we have problems with it.

But Colton is sitting there and has already began acquiring the resources, and by 2017 we will be in compliance with the 33 percent and probably the 50 percent with the resources that we already have contracted for and are in advanced negotiations with. So by January 21, 2018, we will be in compliance with potentially the 2013 regulations in terms of renewable procurement. Coming into compliance is already costing us significant amounts of dollars. We are not in compliance with the 20 percent in compliance period one. We will probably be in compliance in compliance period two, at the expense of several millions of dollars for energy, even short term energy that we simply do not need. We did enter 2011 in kind of a strange situation competitively, our retail rates were significantly higher than those in the surrounding communities primarily served by Edison. Since then the situation has changed because we've been able to terminate or renegotiate various contracts, so now our rates are at or below the surrounding communities, but we're still spending millions of dollars, but the big hit is going to be 2017 when we bring on a landfill gas generator that, assuming San Juan were there, we don't need, but we're bringing it in early. We don't know when San Juan 3 is going away, so you're in a situation of, do we not do anything until San Juan is scheduled to go down? Or do we start procuring resources early? But as we procure the resources, we're procuring renewable resources that are more expensive than alternative thermal resources in the marketplace, so we're taking a financial hit.

The regulations dealing with procurement expenditure limits are unclear. And I would think in my discussions with staff, underappreciated. There doesn't seem to be any discussion where any appreciation on the part of CEC staff that the procurement expenditure limits truly exist and were meant to deal with situations we face, among others, that if you don't need resources and any renewable that you purchase is surplus to your retail load, why should we be out there acquiring the resources until we have a retail requirement? The Regulations, at least in my view and staff's view, is that the Regulations do not deal with this situation and is not appreciated by the Energy Commission staff, or the drafters of the legislation that not all utilities require resources in a specific time period, particularly those entities that are still dealing with the fallout from the 2009-2010 economic downturn in this country.

So as we're going through this, I ask that you consider the unique circumstances of each utility and where they're going to be, okay, it's not that we're in a situation where we're opposing or delaying, it's a situation where we're attempting to minimize the financial impact on a community, but be in full procurement when we have a retail energy requirement that has to be met through additional purchases. So if there are no questions, I appreciate the opportunity to speak to you.

MS. GOULD: Thank you. And the last card, Bill Westerfield from SMUD.

MR. WESTERFIELD: Good morning, Bill Westerfield with SMUD. I'd like to also thank you both for holding this joint workshop and really value the conversation that we hope to have on these Regulations going forward.

First of all, I'd like to briefly address some remarks that my esteemed colleague, Mr. Tutt made earlier on the excess procurement issue. I think there was a question that, Gabe, you had about what commercial situation might a POU have to extend a long term contract. And certainly we're not always able to go out there and get long term contracts for the period that we want them.

But it also concerns me a bit that it seems the proposed regulation assumes that an amendment or modification to a contract is a brand new contract that should be considered just for the period of time for that amendment or that modification. And really, when you have long term contracts and you have the opportunity to maybe extend them for several years, it’s an extension of an existing contract, not a brand new contract. And I think California law would substantiate that.

So I’d like to address most of my remarks to the Section 1240 RPS enforcement provisions. Current law sets forth a clear and limited role for the Energy Commission in enforcement of the RPS on POUs, and I’ll quote: “The Energy Commission may issue a Notice of Violation and correction against a POU for failure to comply with this Article, and the CEC may then refer violations to the ARB for penalties. The CEC takes a decidedly expansive view of its authority by proposing to grant itself the power to recommend penalties to the ARB and make findings regarding mitigating and aggravating factors relating to penalties. Consequently, the proposed regulations include an invitation to the POUs when answering an enforcement complaint to include information pertinent to monetary penalties such as history of past violations, the extent to which the violation will cause harm, that sort of thing. And the CEC justifies collection of this information because it *may* recommend such penalties to the ARB. And it solicits this information even though it has no penalty authority, and nor is there a suggestion in the statute that it does."

But the CEC takes this a step further. The ISOR states: "The Energy Commission's final decision will include all findings of fact, including any findings regarding any mitigating and aggravating factors upon which the ARB will rely." And further it claims the ARB will not re-adjudicate the CEC's decisions and findings of fact upon which the ARB's penalties may be based."

So I'd like to say straight up that making penalty recommendations and asserting ARB intends to accept the CEC's recommendations and findings of fact clearly overstates the CEC's authority under the statute. The statute says that penalties are the province of ARB and not the Energy Commission. And it's explicit on this point.

The role that was given to ARB for

whatever reason and the CEC cannot -– this role of penalties was given to the ARB and the CEC cannot rewrite the law because it believes it's prudent to administer it otherwise.

The enforcement scheme in 339.930 was enacted in SBX 2 or 12, whatever we're supposed to call it. The statutory scheme clearly divides enforcement task between the finding of noncompliance on the one hand, and the assessment of a penalty on the other. The division of responsibility was a legislative compromise that originated in SB 14, if I'm not mistaken, many years ago, but it was a compromise that the Legislature made and not one that the CEC can revise on its own. This was important to POUs at the time when SB 14 was considered, and we continue to view that as important today.

And any assertion that CEC's recommendations are only advisory is underscored by language in the ISOR that ARB does not intend to re-adjudicate CEC's findings on its recommendations. The CEC is clearly attempting by this regulation to heavily influence ARB's decision making, if not appropriate that decision to itself.

If these Regulations are enacted, I expect great deference by the ARB to the penalty recommendations of the CEC. This division of responsibility is unique and SMUD can understand the challenge faced by the agencies in administering it, SMUD is sympathetic to the tough job that the agencies have with this compromise, this legislative compromise. This division requires some vision in how to create a fair process that is true to the legislative compromise; however, this is not the way.

If the CEC finds the statute unworkable, then it should go back to the Legislature for a solution. We strongly believe that the proposed regulation misreads the statute and violates the legislative compromise. And we urge the CEC to reconsider these proposed rules and limit its role to a finding of noncompliance as written in the law.

MS. GOULD: Thank you, Bill.

MR. WESTERFIELD: Thanks very much.

MS. GOULD: Okay, unless there are any additional comments in the room -- oh, yes, Tim.

MR. TUTT: I just wanted to speak a little bit more about the bundling issue and the double-counting question, and consumer protection questions that have been raised today.

AS I've said, SMUD submitted comments in a couple proceedings with the CEC that they should consider this additional benefit that behind-the-meter solar gets in the sense of reducing our retail load and hence our RPS obligation. I've got to make sure we understand, it's not double in the sense of it's counted twice, right? And for a large resource that sells renewable energy to us, 100 percent of that generation counts towards the RPS. For a behind-the-meter resource, it's not part of the RPS for a variety of reasons, it's hard to get them included. It reduces our RPS obligation by currently 20-25 percent of the generation of that facility. By 2020 it will be 33 percent of the generation of that facility, not 100 percent. A large portion of renewable generation within California just will not be counted, that's the way that works. If you want to make sure that that distributed generation doesn't get that extra benefit, then add the generation into the retail load calculation, it's serving retail load in California.

With respect to consumer protection issues, I guess I come from the perspective of working for a publicly owned utility owned by our customers, we understand and want to protect our customers. There are some pretty funky solar companies out there that tell our customers stories, aren't always exactly right. That's the kind of consumer protection we're interested in. We understand the issue about claiming RECs one way or another, and we've run into, for example, at the CEC double-claim of large scale wind RECs between Edison and SMUD, you guys have handled that. The idea that two different entities or companies are making commercial benefit off of the same kilowatt hour of generation is what we're worried about there. We've run into that issue similarly with our green pricing program. We've purchased renewable energy credits, later we've had the third party provider replaced because the companies from those credits were claiming them somewhere else. Those were replaced. We understand that.

We have given our customers the choice of either providing us the RECs when we give them an SB1 incentive, or not. Some of our commercial customers have said, no, we want to keep the RECs, and it’s presumably because they have a commercial purpose for that. The commercial purpose would be that they want to claim that solar generation as part of the cache for their company or their product. And Federal Trade Commission governs the fact that they can claim that or not based on whether they own the RECs. I submit that this does not apply, it’s not consumer protection, for having us or you guys or anybody else -- again, with due respect to my friend, Nancy Radar -- to go out to residential customers and tell them, “You cannot get the value of the solar on your house by selling the RECs to the utility, or if you do, you can no longer say anything about the solar on your house.” You can’t tell your neighbors that you have solar on your house, you can’t point it out to them, that’s not a commercial claim, and it’s not consumer protection to go out and prevent them from talking about the solar on their house. Thank you.

MS. GOULD: Thank you. Okay, anymore comments in the room? Okay, Kevin, are there any WebEx comments? Okay. So Kevin, would you mind unmuting all the lines so we can see if there are any comments on the phone? Okay, it sounds like they're open.

MS. JOHNSON: This is Linda Johnson. I'd like to make some comments.

MS. GOULD: Yes, thank you, Linda. Go ahead.

MS. JOHNSON: Hi. Good morning, I'm from Braun, Blaising, McLaughlin and Smith. And we represent a group of small publicly owned utilities, including the Cities of Cerritos, Moreno Valley, Corona, Colton, Victorville, Pittsburgh, and Rancho Cucamonga. Thank you for the opportunity to comment today.

We submitted written comments on behalf of the small POU Coalition on July 28, 2014, asking the Commission to adopt flexible rules for categorization of power from distributed generation as Content Category 1 to reflect the value of distributed generation to the state's utility grid and to further encourage utilities to make it a priority in their resource mix. Our position has not changed. We do appreciate what you're trying to do with the City on distributed generation in this modification to the rules, but we would also, however, add that if the POU buys bundled RECs from a third party PV system located on a commercial facility, and provides electric service to the commercial facility under a separate meter, the POU's power purchase should be treated like any other wholesale transaction and count as Content Category 1.

We would urge the Commission and the staff to make the changes in the regulation to clarify that this type of transaction would qualify. And like SMUD, we've also dealt with the consumer protection issues; as you're aware, there's a pretty comprehensive treatment of green washing in the state and at the Federal level and we deal with that in contract negotiations with customers, and some of them do want to keep the right to claim and use their renewable generation that's on their facility for all kinds of reasons. And you have to be really careful about dealing with how to use it for Regulatory compliance and also whether or not a customer can use it for marketing purposes, or whatever, in the contract, and sometimes it just doesn't work. And so I think that's dealt with in other forums and regulatory authorities, and so I don't think that should be an issue for consideration in this particular proceeding. It's clear that both the customers and the utilities are very aware of the issues there. Thank you for allowing me to comment today and I appreciate the opportunity to work with you.

MS. GOULD: Thank you, Linda.

MS. WISLAND: Hi. This is Laura Wisland with UCS, I'd like to make some comments.

MS. GOULD: Go ahead, Laura.

MS. WISLAND: Thanks. My name is Laura Wisland. I'm an Energy Analyst with the Union of Concerned Scientists, and I'm sorry I can't be there in person, but I really just want to first of all thank the Energy Commission staff for your hard work on this rule and I plan to follow-up with some written comments. And before I get into my specific comments on the rule, just because we've gone way down into the weeds, appropriately in this workshop, I think it's important to say a couple of things about why the State is making these investments in clean renewable generation resources.

When we talk about the RPS today, it seems like it's all about carbon reduction and, in fact, that’s a huge part of it, and burning fossil fuels, our climate have also incalculable impacts on our state’s economy and public health, I think we’re seeing that loud and clear right now with the drought that we’re currently in. Transitioning away from the fossil fuel resources is making a very important step forward to reducing our reliance on these sources of generation and California is certainly not alone in this program, there’s 29 other states that have an RPS Program. But also I think that people forget that the RPS was originally passed to make sure that we don’t experience rate shocks from being overly reliant on one source of generation. If we’re overly dependent on a resource like hydro power, which as we know is becoming less and less reliable, or natural gas which has been historically very volatile in terms of its prices, our customers are in trouble because we’re much more exposed to potential rate shocks.

So let me talk about a couple quick things. I want to just make some quick comments about the bundle definition. In the past, UCS has been very concerned about the CEC and the PUC developing rules that would treat the exact same resources differently for the purposes of RPS compliance, and generally we still believe that should be the case, that the rule should be equal, provide equitable costs and benefits amongst all the electricity ratepayers in the State. However, I do think that the current changes to the bundle definition which would allow POU-owned behind-the-meter facilities to count towards Bucket 1 could be an important tool to provide some of the POUs, especially the ones that are, you know, smaller and don’t have the ability to sign long term contracts for large generation facilities, would be able to provide them with some valuable flexibility in that program. However, I am concerned like a lot of other commenters today that we do need to be making sure that the megawatt hours that were generated and are associated with those RECs that now would be counted as Bucket 1 are added back to the retail sales calculations so there’s no misunderstanding and there’s no perception that these RECs are somehow being treated with extra compliance value than they have.

And then the other thing I just wanted to quickly bring up were some of the issues that the various employees and customers of the Merced Irrigation District brought up today. First of all, the proposed regulations, I believe, do provide MID with very valuable compliance relief by ensuring that MID is not going to have to purchase renewables to satisfy its load that it would otherwise be able to be satisfied with a low cost hydro power generation from the facilities that they’ve regained ownership of. However, I strongly believe that there is nothing in the statute at all that would allow the Energy Commission to allow MID to avoid its obligation to follow the Bucket requirements in the RPS Program for the renewables that they may be obligated to purchase. There’s no doubt that Merced and other counties in the state are facing significant economic hardships, and luckily Merced has benefited from lower electricity rates when compared to its investor-owned utility neighbors, but it seemed like today folks were making the case that requiring MID to abide by the same rules as every other electricity provider in the state by purchasing bundled renewable energy products from clean generation, it’s going to somehow cause electricity rates to skyrocket and that this could simply be avoided by purchasing unbundled RECs. You know, one of the provisions in the RPS program that requires electricity providers to prioritize transactions that are bundled, it’s in there to protect California jobs and California ratepayers, and that when you buy an unbundled REC, as everybody knows, it can come from anywhere in the Western Interconnect. And that electricity provider would still need to procure electricity to meet load, and I think that sometimes we forget that extra cost when we discuss the relative value of unbundled RECs.

Also, as we all know, the cost of solar PV has experienced historic and unprecedented cost declines over the past seven years to the point where today the price of solar electricity is comparable in many cases to the cost of grid electricity. And these ratepayer benefits are augmented by the fact that Bucket 1 transactions provide stable electricity prices, which is an important attribute that I mentioned earlier. So I think that combined with the fact that CEC rules would potentially allow Merced to make investments in its own district and onsite solar PV generation, and have that count as Bucket 1 would be able to give the Irrigation District adequate flexibility and appropriately address the unique circumstances of the utilities. Thanks and I look forward to working with everybody to finalize these rules.

MS. GOULD: Thank you, Laura.

MR. MILLS: Can you hear me?

MS. GOULD: Yes.

MR. MILLS: I'd like to make a comment.

MS. GOULD: Okay, go ahead.

MR. MILLS: Okay, good, I wanted to make sure you could hear me, I've been pushing this raise hand button and I'm not sure if it had an effect. I guess not. In any case, thank you for fostering a great discussion today regarding the RPS. Again, my name is Steve Mills. I'm with the Alliance for Desert Preservation. And we, along with an informal coalition made up of mutual benefit corporations, community groups, community associations, and businesses and residents of the high desert area of San Bernardino County, submitted a comment letter, actually it was submitted on April 3, the bottom line I'll get to right away is that we absolutely do agree with the concept that behind-the-meter DG should be classified as broadly as possible in terms of PCC 1, and I guess to use the parlance employed today by many speakers, Bucket 1.

We also support a letter that was submitted July 28, 2014 by the Alliance for Solar Choice, which boiled down to its essence said much the same thing. We agree with a lot of the speakers today in terms of the benefits of classifying RECs from customer side DG as PCC 1. It would have the benefit of giving compliance entities an additional compliance tool. The use of RECs from DG as Bucket 1 would also assist in meeting California's current and future RPS goals, and it would harmonize the RPS program with the state's interest in creating a sustainable market for distributed generation which is being facilitated by a number of State policies, including AB 32, GHG Reduction Goals, California Solar Initiative, the New Solar Homes Partnership, the Governor's 12,000 megawatt DG target and, of course, achievement of Zero Net Energy Goals.

And from a public policy standpoint, DG

Systems deployed on the customer side of the meter certainly do fulfill all of the objectives of the RPS, that is the objectives that the RPS was intended to achieve. I don't think anybody here would disagree with a proposition that a megawatt generated by a DG system has just as much energy and green value as a megawatt generated by utility-scale renewable energy facilities in terms of fulfilling the goals of the RPS and all the other state mandates that I mentioned earlier. I do think it's unfortunate that reading the various relevant PUC decisions, there is an artificial distinction made in interpreting the RPS statute, which is 399.16 in order to treat customer-side DG as a PCC 1 or Bucket 3, we don't see any persuasive justification for that, and in the letter that we wrote, we did reference those Decisions and say why we disagree with that statutory interpretation, I won't take the time to do that on everybody's dime here today, but the short answer is that we urge the CEC to determine as broadly as possible in all circumstances involving DG generation, including where the energy is used for onsite consumption, that the associated RECs be deemed PCC 1, otherwise we will stymy the ability of the stakeholders to harness customer interest in DG resources to meet the state climate change goals, and that would be contrary to the clearly articulated State policies that are seeking to support customer side DG. Thank you.

MS. GOULD: Thank you, Steve. Does anyone else on the phone have comments? Okay. Hearing none, I think we'll close the workshop for today. Thank you all so much for joining us and for providing such a good comprehensive conversation, thank you.

(Whereupon, at 11:43 a.m., the workshop was adjourned)

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REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 29th day of April, 2015.

Kent Odell

Kent Odell
CER**00548

TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 29th day of April, 2015.

Karen Cutler

Karen Cutler
Certified Transcriber
AAERT No. CET**D-723